# *Louisiana Public Service Commission*

POST OFFICE BOX 91154
BATON ROUGE, LOUISIANA 70821-9154
www.lpsc.louisiana.gov

Telephone: (225-342-9888)

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LA PUBLIC SERVICE COMMISSION

August 17, 2015

Mrs. Terri Lemoine Bordelon
Records Division, LPSC
602 N. 5th Street
Baton Rouge, LA 70802

**Re: Docket U- 33325; Audit of Louisiana Retail Fuel Adjustment Clause of CLECO Power, LLC for 2009-2013**

Dear Mrs. Bordelon:

This correspondence is being provided along with an *Audit Report* for filing and docketing of this matter in the Commission's Official Bulletin. Please place in the bulletin with a 25 day intervention period and comment period. Please be advised that there is a public and confidential version of this filing.

Should there be any additional questions regarding the above mentioned docket, please do not hesitate to contact me directly.

Sincerely,

*Adrienne Moulton-Henderson*
Staff Attorney

AMH/kr

# REPORT TO THE

# LOUISIANA PUBLIC SERVICE COMMISSION



## AUDIT OF LOUISIANA RETAIL FUEL ADJUSTMENT CLAUSE

**2009 - 2013**

**CLECO POWER, LLC**

**DOCKET NO. X-33325**

**PUBLIC VERSION**

**J. KENNEDY AND ASSOCIATES, INC.**

**570 Colonial Park Drive**
**Suite 305**
**Roswell, Georgia 30075**
**(770) 992-2027**

**August 2015**

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## I. INTRODUCTION AND SUMMARY

Pursuant to the Louisiana Public Service Commission's ("LPSC" or "Commission") General Order regarding the treatment and allocation of fuel and purchased power costs (Docket No. U-21497), J. Kennedy and Associates, Inc. ("Kennedy and Associates") was retained by the Commission at its November 6, 2014 Business and Executive Session to assist the Commission Staff in conducting an audit of Cleco Power, LLC's ("Cleco" or "Company") fuel and purchased power costs for the calendar years 2009 through 2013. This report contains the findings and recommendations of this audit.

The purpose of the audit was to determine the following:

1. Whether the costs passed through Cleco's fuel adjustment clause ("FAC") were prudent;

2. Whether the costs were appropriate and eligible for recovery through the FAC consistent with the Commission General Order dated November 6, 1997 and with sound ratemaking principles;

3. Whether the costs passed through Cleco's FAC produced just and reasonable rates; and

4. Whether the costs passed through the FAC were necessary for the provision of electric service to Louisiana ratepayers.

Kennedy and Associates and the Staff issued multiple data requests to Cleco requesting copies of the Company's detailed FAC filings and information regarding its fuel and purchased power costs and procurement activities by source, forced outages reports, hedging activities, fuel contracts, and reconciliations of costs with per books accounting data. We obtained copies of the Company's monthly detailed confidential FAC filings from Staff for review. We also participated in several conference calls with knowledgeable Company personnel. Kennedy and Associates also obtained market data on the cost of natural gas, coal, petroleum coke, and lignite to determine whether Cleco's purchased gas costs were reasonable. In addition, we reviewed the Staff's FAC audit report covering the years 2003 through 2008 that was issued in Docket No. U-30955.

Kennedy and Associates also reviewed the recent LPSC orders that impacted the level of costs that Cleco was allowed to flow through its FAC. The Docket Nos. U-21453, U-20925(SC) and U-22092(SC) (Subdocket G) Order approved the Dolet Hills Term Sheet which defined the buyout terms of the Dolet Hills Mining Venture ("DHMV") by Cleco and Southwestern Electric Power Company ("SWEPCO"), including the guaranteed minimum ratepayer savings annually of 2% compared to the projected DHMV contract costs through 2011. The related Docket No. U-29797 Order extended rate savings for ratepayers but also authorized recovery of previous lignite savings deferrals over a period of 11.5 years. The Docket No. U-28765 Order authorized Cleco to recover the financing costs incurred during the construction of the Madison 3 (formerly named Rodemacher 3) generating unit through the FAC and directed that these amounts subsequently be refunded with interest through base rates after the unit was placed in service. The Docket No. U-30689 Order established the RPS Collections Surcredit Adjustment rider tariff to refund the financing costs collected through the FAC during the construction of Madison 3 and authorized Cleco to offer a 25% discount, known as the Cleco Alternative Rate for Electricity "CARE", on the fuel portion of qualifying customer bills during the high usage months of July, August and September. The Docket No. U-31792 Order authorized Cleco to recover the equipment and installation costs at Madison 3 for the purposes of test burning biomass fuel (wood chips) through the FAC.

Based on the audit, we have reached the following conclusions:

1. Generally, Cleco complied with the filing requirements as set forth in the LPSC's FAC General Order with one exception. The costs included on the schedules in the monthly FAC filings were consistent with the supporting documentation, including the invoices and contract terms provided with the filings. In addition, all calculations and reconciliations reflected in the filing schedules were accurately performed and properly carried forward to other schedules.

2. Cleco did not comply with the terms of Section IV - Methodologies, Subsection S - Delineation of Affiliate Transactions of the Commission's 1997 FAC General Order by providing annual reports of affiliate transactions for each year during the audit period. Cleco complied with this requirement only for 2009 and 2011. The 2009 report was filed in January 2010. Cleco was not required to file a report for 2011, because it did not include any affiliate transaction costs in its FAC filings that year.

3. Cleco included variable operation and maintenance ("O&M") expenses related to its 2012 and 2013 affiliate power purchases from Cleco Evangeline LLC as recoverable costs in the FAC filings. Variable O&M expenses generally are excluded from recovery through the FAC pursuant to the FAC General Order, however, the Company explicitly requested and the LPSC approved recovery of these variable O&M charges through the FAC in Docket No. U-32223 (See Order Section V.3.d.). Thus, no disallowance or realignment with base rates is necessary or appropriate.

4. Ratepayers were not harmed as a result of affiliate transactions and affiliate contracts as they were deemed to be appropriate and properly computed and reported. Overall affiliate transaction costs recovered through the FAC were at or below market prices. All affiliate transactions were based on contracts that received prior LPSC approval before implementation. All affiliate demand charges were based on long-term contractual charges and were removed from costs recoverable through the FAC.

5. Cleco complied with the terms of the Commission's Docket Nos. U-21453, U-20925 (SC), U-22092 (SC) (Subdocket G) Order. The Order in these dockets dealt with the pricing of lignite under a Term Sheet agreed to by SWEPCO, American Electric Service Corporation ("AEPSC"), and Cleco, including the guaranteed minimum ratepayer savings annually of 2% compared to the projected DHMV contract costs through 2011. Cleco likewise complied with the terms of the Commission's related Docket No. U-29797 Order, which extended rate savings for ratepayers and also authorized recovery of previous lignite savings deferrals over a period of 11.5 years. During the audit period, Cleco included $12.745 million in deferral amortizations and the associated interest utilizing the rate of short term debt in the FAC.

6. Cleco complied with the terms of the LPSC Docket No. U-28765 Order, which authorized the recovery of financing costs incurred during the construction of the Madison 3 generating unit through a kWh surcharge as an addition to the monthly FAC charge. Customers were to be reimbursed amounts collected during the construction phase with interest through base rates once the plant was placed into service. Cleco included financing costs of $25.218 million in the FAC from January 2009 through September 2009. Cleco included additional financing costs in the FAC prior to the audit review period covered in this proceeding. Customers were credited approximately $166.0 million, including interest, for all prior collections from ratepayers during the period from February 2010 through June 2013 through an RPS Collections Surcredit Adjustment rider tariff authorized in Docket No. U-30689, a base rate proceeding. A review of all collections determined that an additional $464,357 in refunds should be made, so

an adjustment to reduce costs was properly processed through the FAC for that amount in the June 2013 operations month.

7. Cleco complied with the terms of the LPSC Docket No. U-30689 Order. This Order not only authorized the RPS Collections Surcredit Adjustment rider tariff to refund the collected AFUDC amounts, but it also authorized Cleco to offer a 25% discount, known as CARE, on the fuel portion of qualifying customer bills during the high usage months of July, August and September. Cleco included $1.733 million of CARE costs in the FAC during the period from 2010 through 2013. These amounts were reasonable and were added only in the summer months.

8. Cleco complied with the terms of the LPSC Order in Docket No. U-32223, which authorized Cleco to recover through the FAC the return of and on equipment and installation costs at Madison 3 for the purposes of test burning biomass fuel (wood chips). These costs were added monthly to the FAC beginning in the operations month of January 2012. During 2012 and 2013, a total of $0.647 million in additional costs were included in the FAC. The recovery of these amounts through the FAC was reasonable.

9. Cleco properly utilized the correct prime interest rate of 3.25% in each month to compute the interest on the cumulative over/(under) recovery of costs.

10. Cleco's cost of natural gas, coal, petroleum coke and lignite purchased during the period 2009 through 2013 was reasonable.

11. There is no evidence that Cleco's plant outages during the period 2009 through 2013 resulted from imprudence or gross negligence by the Company. Errors were made on two occasions at two different units, one by an operator and one by a contract electrician. These errors caused only brief outages and did not require high cost replacement power purchases or incremental maintenance expenses. Thus, we don't recommend any disallowance.

12. Cleco's financial hedging activities had the effect of reducing price volatility in all but one annual period during the audit period, however, they resulted in losses of [redacted] during the five-year audit period, which increased the FAC rate. Over 83% of those losses incurred during 2009 and 2010 and were due primarily to the settlement of long-term financial instruments that were executed prior to the drop in and stabilization of natural gas prices caused by the ramp-up in shale natural gas production. After incurring these losses, the Company discontinued the majority of its hedging activities by early August 2010 and reduced its dependence on natural gas generation, particularly after Madison 3 commenced operation,. The hedging losses continued through July 2012 for those instruments that were based on 24-month forward pricing. No settlements

of financial derivatives occurred after October 2012. We found no evidence that the Company acted imprudently or that the costs incurred were improper. The Company and its hedging consultant continuously reassessed the condition of the markets as well as Cleco's desire to hedge for volatility reduction purposes. Those reassessments eventually led to the decision to place on hold its financial hedging practices until conditions change. We believe that decision was made timely and was appropriate.

We make the following recommendations:

1. Cleco should file the annual reports of affiliate transactions required in Section IV - Methodologies, Subsection S - Delineation of Affiliate Transactions of the Commission's 1997 FAC General Order. Cleco should submit the required annual Affiliate Transaction Reports for the years 2010, 2012, and 2013. A report should not be submitted for 2011 since affiliate transaction costs were not recovered through the FAC that year. In addition, Cleco should submit the required annual reports for 2014 and on a prospective basis.

2. The Company should consider carefully the dual goals of price stability and the provision of electric generation at the lowest possible cost in any decisions to resume financial hedging activities.

## II. OVERVIEW OF CLECO'S SYSTEM

Cleco utilizes both generating resources and limited amounts of purchased power to meet the power requirements of its approximately 284,000 customers in central and southeast Louisiana. Cleco operated and/or owned shares in nine (9) power plants at the end of the audit period. The Company generated the majority of its requirements from solid fuel (western coal, petroleum coke, and lignite) plants. Cleco's remaining plants utilize natural gas to generate power. *Table 1* below summarizes Cleco's owned generating plants, their capacity ratings and fuel types as of the end of the audit period.

**Table 1**
**Cleco Power, LLC**
**Owned Capacity Resources as of December 31, 2013**

| Unit | Name Plate Capacity (MW) | Net Capacity (MW) | Primary Fuel | Generation Type |
|---|---|---|---|---|
| Brame Energy Center | | | | |
| Nesbitt Unit 1 | 440 | 421 | Gas | Steam |
| Rodemacher Unit 2 [(a)] | 157 | 147 | Coal | Steam |
| Madison Unit 3 | 641 | 626 | Petroleum Coke | Steam |
| Acadia Unit 1 | 580 | 568 | Gas | Combined Cycle |
| Teche Unit 1 | 23 | 17 | Gas | Steam |
| Teche Unit 3 | 359 | 335 | Gas | Steam |
| Teche Unit 4 | 33 | 34 | Gas | Combustion |
| Dolet Hills Power Station [(b)] | 325 | 321 | Lignite | Steam |
| Franklin Gas Turbine | 10 | 8 | Gas | Combustion |
| **Total Capacity** | 2,568 | 2,477 | | |

Notes: (a) Reflects Cleco Power's 30% ownership share in the capacity of Rodemacher 2.
(b) Reflects Cleco Power's 50% ownership share in the capacity of Dolet Hills.

Total nameplate capacity for Cleco's generating units was 2,568 MW at the end of the audit period, while its calculated net capacity measured 2,477 MW. The newly constructed Madison Unit 3 was placed in service during 2010 and Acadia Unit 1 was acquired by the Company that same year, which reduced the Company's dependence upon purchased power during the audit period. While the primary fuel for Madison 3 is listed as petroleum coke in *Table 1*, this unit also utilizes large amounts of Illinois Basin Coal, limited amounts of natural gas, and a portion of the unit has been retrofitted to enable it to burn biomass. Acadia Unit 1 is a more efficient low heat rate gas generating unit compared to the other gas generation units in Cleco's fleet.

*Table 2* found on the next page presents a breakdown of the Company's peak demand, sources of power, and uses of power during the audit period as reported in the FERC Form 1 for each year.

Table 2
Cleco Power, LLC
Peak Demand and Power Sources and Uses During Audit Period 2009 through 2013

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| **Peak Demand (MW)** | 2,115 | 2,229 | 2,239 | 2,282 | 2,278 |
| **Power Sources by Type (MWh)** | | | | | |
| Total Generation | 4,902,750 | 8,752,614 | 10,024,954 | 9,143,044 | 9,735,902 |
| Total Purchases | 5,779,469 | 3,140,127 | 1,682,062 | 2,445,219 | 2,157,833 |
| Total Net Power Exchanges | (896) | 1,363 | (297) | (68) | (15) |
| **Total Power Sources** | 10,681,323 | 11,894,104 | 11,706,719 | 11,588,195 | 11,893,720 |
| | | | | | |
| **Generation % of Total** | 45.9% | 73.6% | 85.6% | 78.9% | 81.9% |
| | | | | | |
| **Power Uses by Type (MWh)** | | | | | |
| Total Retail Sales | 8,489,470 | 8,991,892 | 9,027,893 | 8,722,671 | 8,841,580 |
| Requirement Sales for Resale | 360,065 | 693,734 | 1,363,005 | 1,270,740 | 1,313,741 |
| Non-Requirement Sales for Resale | 1,146,975 | 1,383,098 | 637,916 | 835,438 | 960,411 |
| Energy Used by Company | 12,221 | 11,333 | 10,554 | 11,267 | 7,980 |
| Energy Line Losses | 672,592 | 814,047 | 667,351 | 748,079 | 770,008 |
| **Total Power Uses** | 10,681,323 | 11,894,104 | 11,706,719 | 11,588,195 | 11,893,720 |

During this five-year period, Cleco generated 42,559,264 MWh (73.7%) of its power requirements from its own resources while purchasing 15,204,710 MWh (26.3%). *Table 2* shows that the dependence on purchased power was over 50% prior to the 2010 power plant additions and decreased to less than 20% thereafter. The generating fleet has grown larger since the end of the audit period with Cleco's March 15, 2014 transfer of ownership of Coughlin Units 6 and 7 from an unregulated affiliate, Cleco Midstream, LLC, adding 743 MW of combined cycle natural gas net capacity to the system. The Coughlin units are now being used to serve capacity and energy requirements for Dixie Electric Membership Corporation tied to a Purchased Power Agreement ("PPA") that became effective April 1, 2014.

*Table 3* below reflects the total costs to produce each MWh of electric energy and the percentage of energy generated by fuel type for each of the years during the audit period.

**Table 3**

**Cleco Power, LLC**

**Summary of Owned Generaton and Costs During Audit Period 2009 through 2013**

**($ per MWh)**

| | Natural Gas | | Coal | | Lignite | | Petroleum Coke | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Cost | Percent | Cost | Percent | Cost | Percent | Cost | Percent | Cost | Percent |
| 2009 | $105.22 | 33.1% | $27.10 | 21.5% | $26.04 | 45.1% | $34.64 | 0.3% | $52.49 | 100% |
| 2010 | 55.61 | 40.4 | 27.35 | 12.1 | 27.56 | 26.9 | 23.14 | 20.6 | 37.96 | 100 |
| 2011 | 46.39 | 33.8 | 29.48 | 15.6 | 30.99 | 23.6 | 31.70 | 27 | 36.12 | 100 |
| 2012 | 27.81 | 45.8 | 33.03 | 17 | 36.36 | 25.2 | 23.54 | 12 | 30.37 | 100 |
| 2013 | 34.60 | 34.4 | 29.42 | 18.2 | 42.44 | 15.6 | 21.54 | 31.8 | 30.72 | 100 |

Of the total amount of generation during this five year period, 37.8% resulted from the burning of natural gas, 16.5% resulted from the burning of coal, 25.3% resulted from the burning of lignite, and 20.4% resulted from the burning of petroleum coke.

## Fuel and Purchased Power Procurement

All of the fuel and purchased power procurement function for Cleco is performed by two functional areas within Cleco. The Commercial Operations Fuel Management Group manages and performs the fuel procurement function, while the purchased power procurement function is handled by the Energy Operations Group. The responsibilities within these groups are further divided into subgroups that are identified more fully in this section.

Cleco utilizes a combination of bidding procedures and direct negotiations to secure solid fuel contracts. It must consider fuel specifications, logistics, and treatment costs for each generating unit in its decision making process. Natural gas, on the other hand, is purchased from many different suppliers who have interconnection availability to each of the natural gas burning power plants. Natural gas purchases are made for daily or spot purchases as the volumetric needs are determined.

Cleco's Analytic Group performs internal load and generation forecasts on an annual basis, and these estimates are used to determine each generating unit's total fuel requirements for each annual period. Contracts are executed for each year based on inventory status, availability, and price. Solid fuels such as lignite, Powder River Basin coal, and Illinois Basin coal are not subject to availability concerns due to known reserves and plans at the mines to produce the product. Cleco's lignite supply is provided via a mine mouth operation near the Dolet Hills unit with long term commitments for supply. Contracts for the other solid fuels are obtained through the RFP process directed through the Cleco Fuel Group and the Cleco Purchasing Group. Petroleum coke is considered a by-product that is produced by refineries producing crude oil, and since there are no known reserves for petroleum coke, supply risk is minimized by contracting with multiple suppliers to prevent delivery shortages should certain refineries experience a lack of production.

The Energy Operations Group handles the Resource Coordination and the Next Day desks for the Retail Operations line of business for Cleco, and their efforts contribute to the Company's success in accomplishing economic dispatch. This group determines whether additional purchased power will be required to help system needs on a real-time (hourly) basis for both reliability and economic concerns. Cleco relied upon a combination of long-term firm contracts and economy purchases during the audit period.

**Summary of Costs Included in the FAC for Years 2009 through 2013**

*Exhibit 1* details the MWhs and energy costs included in the FAC filings each month during the years 2009 through 2013. The amounts depicted for fossil fuels include the effects of financial hedging costs and Dolet Hills savings and amortizations of prior cost deferrals, all discussed in detail in the sections to follow. They also represent the energy generated and the associated fuel costs, not the amounts purchased for inventory. The amounts for each of the energy sources do not reflect the reductions for energy sold out of the system via off-system sales, amounts associated with special rates, and other LPSC authorized adjustments. As demonstrated in *Exhibit 1* and corresponding to the data provided in *Table 2* found on page 10, the dependence on purchased power was over 50% prior to the 2010 power plant additions and decreased to just over 26% in 2010 and to less than 20% thereafter. The data also shows that the additional in-house generation prevented reliance upon firm purchased power during the years 2010 and 2011. With the exception of 2009, the cost per MWh of fossil fuel generation was less than that for purchased power on an overall basis. In data provided for audit year 2009, fossil fuel costs were driven high due to the effects of financial hedging losses, which will be discussed in greater detail later.

It is important to note that adjustments were made to the monthly FAC filings to remove costs and energy via line items identified as "Time-of-Use Rates." Cleco utilizes these line items to segregate from total system fuel costs individual and discrete purchases dedicated to one or more of three retail and six wholesale customers. These dedicated purchases were accounted for and tracked individually and then summed into the values shown on lines 6 and 24 of the monthly FAC summary reports. Line 6 subtracts the energy associated with the dedicated purchases while line 24 subtracts the costs in dollars. The use of these adjustments ensures that the fuel costs for these time-of-use customers are not commingled with the fuel costs incurred to serve all other customers.

Similar adjustments were made in 2009 and 2010 to the monthly FAC filings to remove costs and energy via line items identified as "Fixed Price Contracts." Cleco utilizes these line items to remove from system fuel costs the energy and related costs associated with one wholesale customer which is billed on a fixed fuel contract. Line 7 subtracts the energy associated with the dedicated purchases while line 25 subtracts the costs associated with that energy, which is similar to the "Time-of-Use Rates" adjustments. The use of these adjustments serves to remove both the energy values and costs applicable for these customers so that they are not included in the fuel costs incurred to serve LPSC-regulated customers.

## III. COMPLIANCE WITH LPSC FAC GENERAL ORDER

The LPSC's 1997 FAC General Order specified certain costs that may be included in an electric utility's FAC as well as costs that must be excluded. Includable costs are:

- Direct cost of fuel purchased from a non-affiliated party.
- Direct cost of fuel purchased from an affiliated party at the lower of cost or market.
- Cost of fuel treatment.
- Cost of transportation by a non-affiliated party.
- Cost of transportation by an affiliated party at the lower of cost or market.
- Cost of emission reagents.
- Nuclear fuel amortization expense.
- Cost of nuclear fuel amortization expense dependent on burn.
- Interest expense on leased nuclear fuel.
- Cost of emergency and economy purchased power.
- Energy-only cost of other purchased power.
- Revenue from emergency and economy sales.
- Energy revenues from firm sales, excluding demand, capacity, and facilities charges.

The General Order also specifies costs that shall be excluded from recovery through the FAC. Excluded costs are:

- Non-fuel operations and maintenance ("O&M") expenses.
- Procurement costs.
- Fuel handling and testing costs.
- Cost (net of revenues) of byproduct disposal.
- Property taxes including ad valorem taxes.
- Depreciation and amortization costs.
- Lease expenses.
- Interest expenses and/or carrying charges on capital investments and inventories.
- Purchased power demand, capacity, or facilities charges.
- Costs of and revenues from transmission for affiliated parties.
- Firm sales revenues for demands, capacity, or facilities.

The first level of review was to determine whether the Company complied with the section of the Commission's General Order specifying includable and excludable costs. A detailed review was conducted of Cleco's monthly confidential FAC filings, which specified the costs that were included and excluded for Cleco's generating facilities and for purchased power. Staff sent out written discovery which focused on specific questions concerning many of the monthly filings. The review indicated that for the most part, the Company complied and did not include any costs that should have been excluded pursuant to the General Order for both its generating units and for purchased power costs, however, Kennedy & Associates did observe one concern with the Company's filings. The Company's payments for purchased power expense from its affiliate, Cleco Evangeline LLC, included not only the fuel expense, but also included variable O&M expenses at the rate of [redacted] per MWh each month. The variable O&M expenses are considered non-fuel O&M expenses and are an excluded item in the FAC General Order, however, it was determined that the Company explicitly requested and the LPSC approved recovery of the variable O&M charges through the FAC in Docket No. U-32223 (See Order Section V.3.d.). Therefore, no disallowance or realignment with base rates is necessary or appropriate.

**Reporting**

"Per books" amounts for amounts in FERC Accounts 447 (Sales for Resale), 501 (Fuel), and 555 (Purchased Power) is the starting point for the total and recoverable costs in the FAC. These amounts are reported in the Economy Sales Report (*Exhibit I*), the Fossil Fuel Plant Report (*Exhibit E*), the Economy and Emergency Purchases Report (*Exhibit G*), and the Other Purchased Power Report (*Exhibit H*) for each month. The FAC General Order requires that the "per books" amounts for each of these accounts be reported in these reports along with all adjustments required to reconcile the "per books" amounts to the recoverable amounts.

In order to test the amounts included in the FAC filings, Kennedy and Associates asked the Company to provide summaries of all general ledger activity from its accounting records along with performed reconciliations for each of the accounts listed above. The information provided by the Company showed that the amounts detailed in the FAC filings reflected the amounts as booked by the Company with no exceptions noted. The Company properly removed all capacity related payments and flowed through 100% of its off-system sales revenues in each monthly FAC filing.

Kennedy and Associates also conducted a detailed review to ensure that the summary data presented on Cleco's monthly FAC reports relating to fuel and purchased power costs was internally consistent and arithmetically correct. We reviewed the Company's detailed fuel cost reports, the purchased power cost reports, and the economy sales reports to verify that the summary data in the FAC report tied to the detailed cost data presented in the separate fuel and purchased power reports for each month in 2009 through 2013. No exceptions were noted. We also performed sample testing of amounts collected from invoices and checked the summation of those amounts for reporting purposes, and again, no exceptions were noted.

Another key component of Cleco's FAC is the calculation of monthly interest on cumulative over- or under-recoveries of costs. *Exhibit B* attached to the Commission's General Order specifies the report format and calculation of the monthly over/(under) surcharges for the operations month. *Exhibit C* attached to the Commission's General Order specifies the manner in which interest is to be applied to Over/Under Recoveries of fuel costs. Kennedy and Associates independently reviewed Cleco's monthly FAC filings to determine whether interest was calculated properly by the Company and whether the Company properly followed the reporting format of the Commission's General Order. We verified that Cleco utilized the prime rate of 3.25%, which was applicable during each month of the audit period, and properly computed the interest on all Over/Under Recoveries of fuel costs.

**Affiliate Transactions**

Cleco participated in limited affiliate transactions during the audit period, and each of these transactions was based on PPAs that received pre-authorization from the Commission. The list below summarizes the PPAs in place during the audit period by indicating the affiliate, contract term, and the LPSC docket for each of the PPAs in place.

| Affiliate | PPA Term | LPSC Docket |
|---|---|---|
| Acadia Power Partners, LLC | Mar 2009-Sept 2009 | U-30727 |
| Acadia Power Partners, LLC | Jan 2010-Dec 2010 | U-31123 |
| Cleco Evangeline LLC | Jan 2012-Apr 2012 | U-32096 |
| Cleco Evangeline LLC | May 2012-Apr 2015 | U-32223 |

As seen above from this list, there were no affiliate transactions during 2011, and each of these PPA's, along with PPAs with non-affiliates, is discussed in more detail in the Purchased Power section of this report. A review of transactions from these affiliate transactions reveals that costs passed through the FAC were consistent with the PPAs approved by the LPSC and that overall costs were at or below market prices.

**Affiliate Transactions - Reporting**

As part of its review of affiliate transactions flowed through Cleco's FAC filings, Kennedy and Associates sought to review the Company's reported affiliate transactions as required by Section IV - Methodologies, Subsection S - Delineation of Affiliate Transactions of the Commission's 1997 FAC General Order. This section seeks information relating to fuel and purchased power costs that an electric utility purchases from an affiliated party and seeks to recover through the FAC. The Order requires that a company file the following information annually:

- Identification of the affiliated party.
- Description of the affiliate relationship.
- Products and services provided by the affiliate.
- Prices, volumes, and other quantitative measures.
- Description of costs included for recovery.
- Computational methodology.
- Market engineering and cost study.
- Comparison of cost to market.

Cleco filed only one annual Affiliate Transactions Report, the 2009 report submitted on January 25, 2010, for the review period. The 2009 report included the information required in the list above associated with the 2009 PPA with Acadia Power

Partners, LLC authorized by the LPSC in U-30727. Cleco was asked to explain why it had not filed the required annual reports for the other years. In response to discovery, Cleco explained that it had only participated in affiliate transactions that were subject to the PPAs listed above and that the LPSC had granted Cleco authorization to recover the costs associated with the energy-related portions of those PPAs through the FAC. It also explained that it participated in no affiliate transactions during 2011. Kennedy and Associates verified that the transaction costs subject to these PPAs were the only affiliate transaction costs recovered through the FAC during the audit period, however, the LPSC's approval of applicable PPAs did not relieve Cleco of its obligation to adhere to the reporting requirements of the FAC General Order. Cleco should abide by the provisions of the General Order and submit the required annual Affiliate Transaction Reports for the years 2010, 2012, and 2013. A report is not necessary for 2011 since affiliate transaction costs were not recovered through the FAC that year, although Cleco should make an informational filing for 2011 stating that it did not engage in any affiliate transactions that affected the costs included in the FAC for that year. In addition, Cleco should submit the required annual reports for 2014 and on a prospective basis.

## IV. COMPLIANCE WITH OTHER LPSC ORDERS

During the review period, the LPSC issued orders that specifically affected the fuel or purchased power expense that Cleco was allowed to flow through its FAC. In addition, the 2009 through 2013 FAC was affected by Commission orders issued prior to 2009. This section will describe those orders, summarize the applicable findings, analyze the effect on Cleco's FAC, and evaluate whether the Company was in compliance with the Commission orders.

### Dolet Hills Deferral

The Commission's Order in Docket Nos. U-21453, U-20925 (SC), U-22092 (SC) Subdocket G was issued to approve a proposed Term Sheet entered into on April 17, 2001 among Cleco, SWEPCO, and American Electric Power Service Company. The Term Sheet arose out of litigation, pending in federal district court since 1997, involving Cleco, SWEPCO, and the miner that had been supplying lignite to the Dolet Hills Power Plant, which is owned 50 percent by Cleco and 50 percent by SWEPCO. The parties settled the litigation along the following lines:

1. Cleco and SWEPCO agreed to buy out the existing miner, The Dolet Hills Mining Venture ("DHMV"), and replace it with a SWEPCO subsidiary as the new miner ("SWEPCO Miner"). The actual name of the new entity is Dolet Hills Lignite Mining Company LLC.

2. Cleco, SWEPCO, and the SWEPCO Miner entered into a Lignite Mining Agreement that will govern operations and pricing at the lignite mine that serves the Dolet Hills Power Plant.

3. Ratepayers were guaranteed minimum savings annually of 2% of the projected costs under the DHMV contract costs in all years of the new contract, through 2011.

4. If the SWEPCO Miner costs exceed 98% of the projected DHMV costs, Cleco and SWEPCO will be permitted to defer the unrecovered amounts. Ratepayers will still receive the 2% guaranteed savings. In years when the SWEPCO Miner costs are below 98% of the projected DHMV costs, this cost differential will be applied first to the recovery of any deferred amounts. After the deferred amounts are recovered, any additional savings will be returned to customers through the FAC.

The Term Sheet specified how the benchmark, or "would have been" DHMV, costs were to be calculated in order to ensure the 2% savings. According to Paragraph 5 (b) of the Term Sheet, the DHMV costs shall be based on the contractual minimum quantity of 2,434,000 tons of lignite (assuming a heat value of 6,780 Btus per pound) at $1.445/mmBtu, plus additional Btus at $1.07/mmBtu. These calendar year prices will be escalated each year thereafter based upon actual changes in the published GDP-IPD index in order to project the "would have been" DHMV costs. Any SWEPCO Miner costs in excess of 98% of the DHMV benchmark would be deferred pursuant to the Term Sheet as described earlier.

Cleco and SWEPCO determined that the 2001 authorized formula failed to operate in the manner contemplated by the parties, so they filed a Joint Application with the Commission in November 2006 in Docket No. U-29797 seeking to revise the formula and to collect over time the unrecovered amounts that had been deferred. Cleco and SWEPCO claimed that over $75 million had been saved for ratepayers since the SWEPCO miner replaced DHMV as the miner. An Uncontested Stipulated Settlement was reached and was approved by the Commission in December 2007. The main provisions included in the latter settlement are as follows:

1. Cleco and SWEPCO ratepayers would continue to be guaranteed 2 percent savings over the DHMV "would have been" costs.

2. There would be a two-year recovery of the deferred amounts for SWEPCO and an 11.5 year recovery for Cleco.

3. Carrying charges at the "prime rate," otherwise recoverable under the Commission's Fuel Adjustment Clause General Order, would be reduced to the cost of short-term debt for each of the Companies.

4. The 2% savings were to be flowed through directly to Cleco and SWEPCO ratepayers via their respective Fuel Adjustment Clauses.

5. The management fee for the SWEPCO Miner could be collected only if the SWEPCO Miner costs are less than the benchmark and at only 75% of market prices for such management fees.

6. Cleco Power and SWEPCO commit to operate Dolet Hills, if economic, through 2016, five years longer than its then current expected useful life.

The effects of the monthly cost savings and the 11.5-year deferral amortization were reflected properly in the cost of fuel in line 19 of the monthly FAC filings. The FAC filings include the spreadsheet workpaper showing the total costs and the reduced cost allowable for recovery through the FAC. During the audit period, $12.745 million in deferral amortizations were realized, along with interest utilizing the rate of short term debt. The annual deferral amortization amounted to over $2.5 million each year. Cleco properly followed the calculations contained in the Term Sheet, as modified in December 2007, to determine the appropriate monthly adjustments.

**Docket No. U-28765 – Madison 3 Carrying Costs**

Cleco filed an application on May 4, 2005 with the LPSC seeking certification to construct a 600 MW solid-fuel generating plant at the Rodemacher power station. The plant was originally referred to as Rodemacher 3, but the name was changed to Madison 3. As part of its request to help with cash flow during the construction period for a project with capital costs of over a billion dollars, the Company requested that it be allowed to recoup 100% of its financing costs, or allowance for funds used during construction ("AFUDC"), through a kWh surcharge as an addition to the monthly FAC charge. The Commission approved recovery from retail customers of approximately $149 million, representing current recovery of approximately 75% of the LPSC-jurisdictional estimated AFUDC, and the creation of a regulatory liability. Customers were to be reimbursed amounts collected during the construction phase with interest after the plant was placed into service.

During the audit period, Cleco collected $25.218 million in financing costs through the FAC from January 2009 through September 2009. Customers were then credited approximately $166.0 million, including interest, from February 2010 through June 2013 through the RPS Collections Surcredit Adjustment rider tariff authorized in Docket No. U-30689, a base rate proceeding. The tariff was cancelled effective on July 1, 2013. A review of all collections determined that an additional $464,357 in refunds should be made, so an adjustment to reduce costs was processed through the FAC for that amount in 2013. Based on a review of all calculations for charges in 2009 and the resulting balances in the regulatory liability account, the Company followed the provisions outlined by the Commission in its May 12, 2006 Order in Docket No. U-28765.

**<u>Docket No. U-30689 – Cleco Alternative Rate for Electricity "CARE"</u>**

The CARE program, authorized by the Commission as part of the Docket No. U-30689 base rate proceeding, offers a 25% discount on the fuel portion of customer's bills for those who qualify for the high usage months of July, August and September. This discount is added to the cost of fuel recovered through the FAC so that the cost of the program can be shared by all ratepayers. CARE costs included in the FAC from 2010 through 2013 amounted to $1.733 million. A review of the applicable workpapers shows that the costs added were reasonable and were added only in the summer months as defined above.

**<u>CLE Pipeline Intrastate Costs</u>**

In June 2003, pipeline assets owned by an affiliate of Cleco, CLE Intrastate Pipeline ("CLE"), were transferred to Cleco. Prior to the transfer, CLE charged Cleco a transportation charge of $0.031 per Dth for delivery of gas from interconnects with Trunkline Gas Company, Crosstex LIG, LLC and ANR Pipeline Company to Cleco's Rodemacher and Teche power stations. That transportation charge had traditionally been recovered through the FAC. Cleco requested that it be allowed to recover the pipeline costs through the FAC and not base rates. The adjustment was approved by a letter from the Secretary of the Commission dated March 31, 2005. The adjustment was discontinued in the operation month of December 2009 as the former CLE assets were subsequently included in the determination of base rates. $0.412 million in costs were included in the FAC during 2009. The recovery of these amounts through the FAC was appropriate.

**Docket U-31792 - Biomass Fuel Test Burn**

Cleco received authorization from the Commission on November 4, 2001 to recover approximately $2.7 million that it incurred for the new equipment and related installation at Madison 3 in order to test burn biomass fuel (wood chips) at the unit through the FAC until such time as the cost recovery could be switched to base rates. The costs were added monthly to the FAC beginning in the operations month of January 2012, consisting of both the return of an on the costs for the new equipment. During 2012 and 2013, a total of $0.647 million in additional costs were added to the FAC, and the recovery of these amounts through the FAC was reasonable and appropriate.

**Economic Development or Site Specific Rates**

During the audit period, Cleco entered into and was subject to a number of Site Specific Rate Agreements. These agreements, approved individually by the LPSC, serve to encourage employment in the territory served by Cleco by offering discounted FAC rates.

## V. CLECO COST OF FUEL

Cleco uses four primary sources of fuel for its owned generation: natural gas, coal, petroleum coke and lignite. Nesbitt Unit 1, Acadia Unit 1, Teche Units 1, 3, and 4, and the Franklin Gas Turbine utilize natural gas as their primary fuel source. Small amounts of natural gas are also burned at Rodemacher 2, Madison Unit 3, and at Dolet Hills. None of these plants burn fuel oil anymore, though very limited amounts were burned during the review period in the last audit. Rodemacher 2 uses Powder River Basin coal as its primary boiler fuel. Madison Unit 3 burns primarily petroleum coke and Illinois Basin coal and also has the capability of burning biomass materials. Dolet Hills employs lignite as its primary boiler fuel. The following subsections of this report will address the reasonableness of the costs of each of these fuel sources during the 2009-2013 audit period.

### Cost of Natural Gas

Kennedy & Associates reviewed several sources of data to analyze the reasonableness of Cleco's cost of fuel for its gas-fired generating units. First, we reviewed the contracts utilized by the Company to purchase its natural gas. Second, we compared the monthly cost of gas per mmBtu purchased by Cleco with the monthly average Henry Hub gas price indices.

During the 2009-2013 audit period, Cleco primarily relied upon daily and monthly spot market purchases on an as-needed basis only. The Company did not utilize long-term gas purchase contracts because they typically include minimum volume requirements or price penalties that could increase the cost per mmBtu above market indices pricing. The Company did, however, begin to utilize outside storage in June 2010 to help provide natural gas supply reliability and purchase flexibility due to the heightened dependence on gas generation. Cleco incurred monthly gas storage fees of $180,000 and $184,000 per month through the end of the audit period as a protection against supply interruption as well as a balancing of gas requirements for the gas generating units on a daily basis. In order to accomplish this, the Company leased 1 billion cubic feet of gas storage from Pine Prairie Energy Center to house its owned gas.

Cleco relied primarily on coal, petroleum coke and lignite units to provide base load power throughout the audit period. Cleco relied upon its gas units to fill any remaining base load requirements, to meet peak demands, to replace coal, petroleum coke and lignite generation during planned and forced outages, and to follow daily and hourly load swings.

In order to determine whether the Company's cost of spot gas was reasonable, Kennedy & Associates compared the monthly cost of gas per mmBtu purchased by Cleco with the average monthly Henry Hub gas price indices. The comparison to these indices provides for a reasonable measure of market prices that Cleco could have accessed during the audit period. The Henry Hub index is widely utilized by the LPSC in comparison of gas prices and it was used in conjunction with the Delaney Settlement to reprice the Evangeline contract for Energy Louisiana, LLC in Docket No. U-23356. The source of the information is the monthly actual average spot prices paid as published by the U.S. Energy Information Administration ("EIA"). It should be noted that the Company relies upon the forward-looking daily index and not necessarily a backwards looking monthly index for its daily spot gas purchases. The prices per mmBtu utilized in our analysis represent the booked commodity-only costs of natural gas purchased in any given month. All transportation, imbalance costs, storage fees, and financial hedging costs were removed for purposes of the comparison. [redacted]

[redacted]

[redacted] The graph depicted as *Exhibit 3* shows Cleco's weighted average cost of gas compared each month to Henry Hub index prices. The graph shows that Cleco's cost of gas was quite close to the Henry Hub average during all the months. Based upon this overall comparison, it appears that Cleco's natural gas costs for commodity purchases were reasonable.

**Cost of Coal and Petroleum Coke**

Kennedy & Associates reviewed several sources of data to analyze the reasonableness of Cleco's cost of coal and petroleum coke for its Rodemacher 2 and Madison 3 generating units. First, we reviewed the long-term coal and petroleum coke contracts. Second, we reviewed Cleco's rail and waterway transportation contracts for delivery of both commodities to its power plants. Finally, we compared Cleco's EIA Form 923 delivered coal and petroleum cost data for coal purchases with that of other Louisiana utilities to determine price reasonableness.

Rio Tinto Energy America, Peabody Energy and Cloud Peak Energy supplied the vast majority of Powder River Basin coal for Rodemacher 2 during the audit period. Cloud Peak Energy is a corporate spin-off of Rio Tinto Energy America. Cleco had long-term fixed price supply contracts effective with these companies throughout the entire audit period. The contracts provide for the full requirements to support the minimum planned dispatch of Rodemacher 2. The largest area of cost involved with Cleco's purchase of coal for Rodemacher 2 relates to the delivery of the fuel from the Powder River Basin of Wyoming to the power plant. This transportation is captive to the Union Pacific Railroad Company. The contract that was in place throughout the entire audit period expires on December 31, 2016.

The Illinois Basin coal burned at Madison 3 was supplied by Peabody Energy, Foresight Coal Sales and Knight Hawk Coal, LLC during the audit period. Contracts with these companies typically were one or two-year fixed amount contracts. The majority of petroleum coke burned at Madison 3 was supplied by oil refineries located along the Lower Mississippi River and based on long-term contracts ranging from three to five years. Pricing for all petroleum coke contracts and the limited amount of spot purchases is tied to the Jacobs Consultancy Petroleum Coke Quarterly Monthly Price Index, also referred to as the "PACE" Monthly Index. The petroleum coke is a by-product of the oil refinery process and is not considered a fuel produced specifically for a market. Cleco receives delivery of the Illinois Basin coal and its petroleum coke at Madison 3 via barges on the Mississippi River and Red River by Savage Services.

Cleco also utilized spot coal and petroleum coke purchases during the audit period when necessary. The Company makes these spot purchases when favorable market and quality conditions occur for certain types of coal and petroleum coke to allow the Company to maximize generation of these low cost forms of power. In making its decisions to make spot purchases, the Company first determines the quantities that it is required to take under its purchase agreements with the providers for Rodemacher 2 and Madison 3. Cleco may purchase additional spot coal and petroleum coke to fill remaining requirements and to adjust inventory to more optimal levels. [redacted] tons of spot coal purchases were made for Rodemacher 2 during 2011. During that same year, [redacted] tons of spot coal purchases were made for Madison 3 and another [redacted] were made in 2013, and no other spot purchases were made for those or any other units.

*Table 4* below portrays Cleco's costs per ton for its two coal units broken out separately between commodity and transportation costs for each year during the audit period. As demonstrated in the table, the commodity cost per ton for the Powder River Basin coal burned at Rodemacher 2 is much less than it is for the Illinois Basin coal burned at Madison 3, however, that cost differential is eased due to the much cheaper cost of barge transportation for the Illinois Basin coal compared to the rail transportation costs for the Powder River Basin coal. The transportation costs make up approximately [redacted] of the cost of delivered coal for Rodemacher 2 and approximately [redacted] for Madison 3.

[redacted]

Kennedy and Associates compared Cleco's delivered and burned coal costs to those of other electric utilities within Louisiana to assess the reasonableness of Cleco's coal costs. This comparison was based upon EIA Form 923 filing data reported by each of the companies in the area. These required filings report the cost and quality of fuels for electric plants on a monthly basis. This information is accumulated on an annual basis for all domestic utilities by the EIA. Public access to the data is provided in Excel format through a link on the EIA website. The Form 923 data was retrieved for the 2009 through 2013 audit years and sorted to select company data in the state. The data resulting from this final sort represented all contract and spot purchases for the peer group companies.

Cleco's total costs of coal each month in each year was very close, if not lower, to the costs reported for the other Louisiana utilities. Each of these utilities suffer from the fact that their transportation costs sometimes outweigh the commodity costs by a large margin, especially for coal received from the Powder River Basin. The transportation costs can be a significant component of the overall cost of coal and can vary significantly between utilities. For the entire 2009-2013 audit period, Cleco's cost of transportation accounted for almost 50% of its total cost of delivered coal. Based on our analysis of regional coal costs, Cleco's total cost of coal appears reasonable.

*Table 5* below portrays Cleco's costs per ton for petroleum coke delivered to the Madison 3 unit broken out separately between commodity and transportation costs for each year during the audit period. Even though 2009 data is reported, product for that year was purchased mainly for testing purposes only. As described above, the unit did not begin full commercial operation until February 2010. As can be seen in the data, average transportation costs decreased every year during the audit period. Commodity prices also fell considerably in 2012 and 2013 due in part to the large increase in petroleum coke production which in turn led to an increase in U.S. exports to a level above 80%.

[redacted]

EIA Form 923 filing data was reviewed for all the units nationwide that burn petroleum coke. According to this data, costs were consistently reported for only seven such units during the audit period. The only other unit burning petroleum coke in Louisiana is located at the Roy S. Nelson power station, a cogenerating unit owned by Nelson Industrial Steam Company. Cleco's cost of petroleum coke is reasonable when compared to that for other utilities driven by the close proximity of many refineries in the region helping to keep transportation costs low. As mentioned above, commodity pricing is all index driven.

**Cost of Lignite**

Cleco relies on long-term contracts to supply its lignite fuel. The 650 MW Dolet Hills power plant is jointly owned by Cleco and SWEPCO, with CLECO serving as the plant's operator. Cleco owns 50% of this generation station. Dolet Hills obtains all of its lignite pursuant to a long-term arrangement with the Dolet Hills Lignite Company ("DHLC"), which is also now co-owned by Cleco and SWEPCO, with SWEPCO being the operator. There are two sets of lignite reserves providing the supply for DHLC. The Dolet Hills Lignite Reserves provide the primary supply and are located adjacent to the plant in the Dolet Hills area of DeSoto Parrish in Louisiana. Supplemental lignite for Dolet Hills is supplied via the Oxbow Mine Lignite Reserves located near Coushatta, Louisiana. Cleco anticipates that the lignite from these mines will be sufficient to fuel Dolet Hills until at least 2036. An estimated 73 million tons of remaining reserves were available at the end of 2013.

Kennedy and Associates did not rely on a market test to assess the reasonableness of Cleco's lignite fuel costs. That is because all of the plants included in EAI Form 923 data regarding market pricing obtain lignite under long-term contracts and do not rely on spot purchases. In addition, there are only three regional lignite plants reported in the Form 923 data for comparison purposes. We did review the pricing of the lignite purchases for the Dolet Hills Mine under the DHLC pricing arrangement amended by the Commission in 2007, as discussed above, as well as the pricing for the Oxbow Mine as authorized by the Commission in 2009 when Cleco and SWEPCO acquired ownership through DHLC. That review indicates that the pricing for lignite purchases was consistent with the pricing arrangement authorized by the Commission. Cleco's lignite fuel costs experienced large increases during the audit period. Commodity prices averaged only about [redacted] per ton during the first three years of the audit period but increased to approximately [redacted] per ton in 2012 and [redacted] per ton in 2013. The Company cited several reasons for the increases through discovery. First, drought conditions in 2011 required additional rehabilitation expenditures in 2012. Second, heavier than normal rainfall amounts in 2012 resulted in a reduction of lignite uncovered. Third, accessible areas mined during the period required additional pre-stripping costs. Finally, due to the planned major outage starting in October 2013, fewer tons were required to be on hand. A large portion of the costs to operate the lignite mines is fixed, such as land lease costs, so lower production leads to higher pricing per ton. Based on the data reviewed, Cleco's costs for lignite purchases during the audit period do not appear unreasonable.

## VI. GENERATING PLANT OUTAGES

The total costs flowed through the FAC may be affected by generation plant outages. If and when a generation plant is taken off-line for maintenance, refueling, or because a malfunction occurs, the Company needs to obtain replacement power, either through higher cost generation or through additional purchases from other sources. Kennedy & Associates examined outages for the Company's generating plants during the audit period to determine whether there were any outages caused by imprudence or negligence on the part of the Company and, if there were, whether these outages resulted in higher costs to Louisiana ratepayers.

Through discovery, the Company provided detailed outage reports for all of their generating plants from 2009 through 2013. Of particular concern is whether Cleco experienced any extended planned or forced outages at its solid fuel and large gas units since they typically represent the lowest cost generation alternatives for the Company. When these units are removed from service, the Company must make up the lost generation with purchases and/or additional generation from its smaller gas-fired generating plants having a net capacity of less than 50 MW as reflected in *Table 1*. Both of these alternative sources of power have generating costs that exceed the low running costs of the solid fuel and large gas units.

Kennedy & Associates focused its attention on the outage experience at the coal, lignite, petroleum coke, and large gas units. The smaller gas units do not fulfill any base load requirements and are run only on an as-needed basis. In addition, the Company can oftentimes purchase economy power cheaper than it can generate power through these gas units. Thus, outages at the smaller gas units are not as economically critical as those experienced at the solid fuel and large gas units and were not subjected to further scrutiny in this audit. In order to evaluate the performance of each of the units, Kennedy and Associates reviewed the performance of Cleco's power plants relative to industry averages. We also reviewed outage reports for the audit period supplied by the Company through discovery.

In response to discovery, the Company provided various comparisons of industry performance data to highlight how the Company compared to industry averages in each of the audit years. The data used in the Company's comparison was gathered from the North American Electric Reliability Council's ("NERC") Generating Availability Data System ("GADS") for the audit period. Hundreds of utilities participate in this data gathering system that contains data for thousands of generating units primarily throughout the United States and Canada. Other companies in other countries have also begun to participate. The data is collected for 63 separate generator unit groups with distinctions based on such factors as size and fuel type. Based on the Company's comparisons, which were checked against NERC published data for the audit years, relevant information related to the solid fuel and large gas units has been replicated in the *Table 6* found on the next page.

**Table 6**
**Cleco Power, LLC**
**Generating Unit Performance**

| | 2009 | 2010 (1) | 2011 | 2012 | 2013 | Average (09 - 13) |
|---|---|---|---|---|---|---|
| **Equivalent Availability Factor** | | | | | | |
| Dolet Hills Power Station | 81.86 | 86.04 | 86.33 | 84.49 | 56.12 | 78.97 |
| NERC All Lignite | 85.49 | 85.15 | 85.13 | 86.07 | 83.13 | 84.99 |
| | | | | | | |
| Rodemacher Unit 2 | 87.73 | 85.14 | 89.73 | 89.01 | 85.62 | 87.45 |
| NERC Coal (400-599 MW) | 81.12 | 81.33 | 83.70 | 82.64 | 83.25 | 82.41 |
| | | | | | | |
| Madison Unit 3 | | | 72.45 | 86.01 | 82.41 | 80.29 |
| NERC All Pet Coke | | | 82.68 | 82.76 | 81.81 | 82.42 |
| | | | | | | |
| Nesbitt Unit 1 | 96.10 | 93.63 | 98.08 | 95.15 | 80.86 | 92.76 |
| NERC Gas (400-599 MW) | 82.52 | 79.78 | 77.10 | 76.30 | 75.90 | 78.32 |
| | | | | | | |
| Acadia Unit 1 | | | 88.80 | 82.69 | 91.95 | 87.81 |
| NERC All Gas CC Block Units | | | 84.02 | 84.50 | 85.49 | 84.67 |
| | | | | | | |
| Teche Unit 3 | 67.65 | 92.31 | 74.86 | 86.87 | 74.19 | 79.18 |
| NERC Gas (300-399 MW) | 86.30 | 85.86 | 84.85 | 85.85 | 76.12 | 83.80 |
| | | | | | | |
| **Forced Outage Rate** | | | | | | |
| Dolet Hills Power Station | 8.13 | 6.43 | 2.30 | 4.91 | 11.06 | 6.57 |
| NERC All Lignite | 3.88 | 3.00 | 3.14 | 5.80 | 4.53 | 4.07 |
| | | | | | | |
| Rodemacher Unit 2 | 3.76 | 4.86 | 1.82 | 2.69 | 5.51 | 3.73 |
| NERC Coal (400-599 MW) | 6.45 | 5.58 | 4.86 | 5.36 | 5.41 | 5.53 |
| | | | | | | |
| Madison Unit 3 | | | 5.14 | 6.68 | 4.43 | 5.42 |
| NERC All Pet Coke | | | 5.60 | 4.72 | 6.99 | 5.77 |
| | | | | | | |
| Nesbitt Unit 1 | 0.35 | 0.45 | 0.28 | 0.81 | 6.30 | 1.64 |
| NERC Gas (400-599 MW) | 9.74 | 13.18 | 16.69 | 18.25 | 13.07 | 14.19 |
| | | | | | | |
| Acadia Unit 1 | | | - | 0.13 | 0.30 | 0.14 |
| NERC All CC Block Units | | | 5.04 | 5.04 | | 5.04 |
| | | | | | | |
| Teche Unit 3 | 1.45 | 0.91 | 0.31 | 2.23 | 5.10 | 2.00 |
| NERC Gas (300-399 MW) | 6.40 | 9.59 | 9.51 | 9.22 | 17.79 | 10.50 |

(1) Acadia Unit 1 and Madison Unit 3 data is excluded for 2010 because both units began running for Cleco during 2010. A full year of data was not available and these units experienced addititonal expected startup commissioning outages.

Source: Cleco Response to LPSC Staff Data Request 1-17 and NERC GADS Reports

The equivalent availability factor ("EAF") is defined as the percentage of time that a unit is capable of providing service, whether or not it is actually in service, but adjusted for any deratings in its capability level. As demonstrated in the data in the chart, the five-year EAF NERC industry average for lignite units was 84.99%. The Dolet Hills lignite unit had an EAF close to the NERC industry average for each individual year except in 2013. [redacted] Cleco's only coal unit is Rodemacher Unit 2. It had a five year average EAF of 87.45%, better than the NERC industry average of 82.41% for similar size coal units. In fact, its EAF exceeded the industry average in each of the five years. The Madison 3 petroleum coke unit was placed into service during 2010. Discounting the 2010 results because of the planned and unplanned effects associated with the start-up commissioning for this unit, the only year that the EAF for Madison Unit 3 did not exceed the NERC industry average for similar plants was in 2011. [redacted] Nesbitt Unit 1's EAF far exceeded the NERC industry average in all years and by an average of over 14%. The new Acadia combined cycle gas unit achieved an average EAF greater than the average for similar units, especially after discounting results for the initial year of Cleco operation in 2010. Without considering the 2010 data, the average EAF for Acadia Unit 1 was actually more than 3% higher than the industry average. The Teche 3 power plant EAF was several points under the industry average in both 2009 and 2011, causing the five-year average EAF to be over 4% lower than the industry average. [redacted]

The forced outage rate ("FOR") represents the percentage of time that the unit is unavailable for service due to an unplanned component failure or other conditions that require the unit to be removed from service immediately or before the next weekend. Cleco's units posted FOR's below industry averages with the exception of the Dolet Hills lignite plant and the Madison Unit 3 petroleum coke plant. When 2010 data is removed from the equation to account for the start-up nature of Madison Unit 3 that year, only the Dolet Hills plant posted a higher than average FOR. The average FOR during the five-year period for Dolet Hills was 6.57%, compared to the NERC industry average of only 4.07%. The outage experiences during 2009 and 2013 caused this overall difference. In 2009, Dolet Hills had a FOR of 8.13% compared to the industry average that year of 3.88%. [redacted] In 2013, Dolet Hills had a FOR of 11.06% compared to the industry average that year of only

4.53%. [redacted]

The data suggests that the overall EAF and FOR were within reasonable ranges for each of the major units during the audit years. As explained by the Company through discovery and as detailed in the Company's outage reports, these reported issues were addressed in a timely fashion and the performance improved significantly, back up to and in some cases exceeding the NERC averages for similar units.

Kennedy and Associates reviewed the planned and forced outages experienced by Cleco at each of its power plants during the five year audit period, again focusing on the solid fuel and larger gas units. A summary of all outages, planned and forced, for the audit period was supplied by the Company through discovery. In addition, detailed reports for all the plants were provided reflecting more details about each of the outages and the impact on operating statistics. [redacted] We do not recommend disallowances for these errors due to the minimal effects on fuel and purchased power expense. There were no other reported cases of Company operator or maintenance errors or equipment design malfunctions causing outages. Based on the outage information reviewed, Kennedy and

Associates does not recommend a disallowance of fuel costs due to imprudence or negligence on the part of the Company.

## VII. PURCHASED POWER COSTS

Even though the Company's own generated energy increased significantly during the audit period from less than 50% of power needs to over 80%, Cleco still had to rely upon power purchased under both firm contracts and via economy purchases from the wholesale market. During the audit period, Cleco participated in long-term contracts with two independent power producers directly connected to its power grid. *Table 7* provides a summary of purchased power by type and by year during the audit period. The amounts do not reflect reductions for power sales out of Cleco's system. The amounts are reflected monthly in *Exhibit 1*.

**Table 7**
**Cleco Power, LLC**
**Summary of Purchased Power By Source**
**($ per MWh)**

| | Economy Purchased Power | | | Firm Purchased Power | | | Total | |
|---|---|---|---|---|---|---|---|---|
| Year | MWh | Cost | % of Requirements | MWh | Cost | % of Requirements | MWh | % of Requirements |
| 2009 | 2,533,587 | $35.60 | 23.6% | 3,249,273 | $33.70 | 30.3% | 5,782,860 | 53.9% |
| 2010 | 3,147,213 | 43.90 | 26.4 | - | - | - | 3,147,213 | 26.4 |
| 2011 | 1,617,892 | 41.55 | 13.9 | - | - | - | 1,617,892 | 13.9 |
| 2012 | 936,005 | 28.58 | 8.3 | 1,233,392 | 26.99 | 10.9 | 2,169,397 | 19.2 |
| 2013 | 834,455 | 33.10 | 7.2 | 1,127,236 | 36.88 | 9.7 | 1,961,691 | 16.9 |

During the audit period, Cleco participated in long-term capacity contracts with independent power producers directly connected to its power grid. The Evangeline Station Units 6 and 7 were controlled by Williams Power Company during 2009. Cleco had a four-year contract with Williams Power Company for 500 MW of capacity and energy through the end of 2009. Acadia Power Block 1 was controlled in 2009 by Cleco-affiliate Acadia Power Partners, LLC, which was a wholly owned subsidiary of Cleco Midstream Resources LLC. Cleco executed a fixed contract for 235 MW of the Acadia Power Block 1 capacity and energy during the months of March 2009 through September 2009. Cleco also contracted for capacity and energy during the months of April through October 2009 with NRG Power Marketing, Inc. Under that contract, Cleco purchased 200 MW from June through September and 50 MW during all other months. As can be seen in *Table 7*, the Company did not rely on firm purchases during 2010 and 2011. As noted in the prior FAC audit report, transmission constraints had hampered Cleco's ability to contract capacity with more suppliers at competitive rates for some time. Cleco acquired 50% of the Acadia Power Station and built Madison 3 to address those concerns and provide much needed capacity. With the introduction of those units into its generation fleet, firm purchases of power virtually ceased until 2012. Cleco entered into a contract with NRG Power Marketing, Inc. for 200 MW of capacity and energy from January 2012 through April 2012. Cleco also entered into two contracts with Cleco Evangeline PPA, an affiliate of Cleco and a wholly owned subsidiary of Cleco Midstream Resources LLC, for capacity and energy through April 2015. The first contract was for 250 MW of capacity and energy for the months January 2012 through April 2012. The second contract was for 730 MW of capacity and energy from May 2012 through April 2015.

As can be seen in *Table 7* above, firm purchases made by Cleco from its affiliate, Cleco Evangeline, LLC were approximately $2 per MWh less than the average for economy purchases in 2012 and approximately $3 per MWh more during 2013. Based on the proximity of the average costs over the two years and the inclusion of variable O&M at a rate of [redacted] per MWh included with the cost of fuel, as noted in the affiliate section above, the affiliate transactions for purchase power appear reasonable.

The amounts reflected in *Exhibit 1* shows the total costs of purchased power from Cleco's FAC filings, excluding demand charges. The Company properly removed all demand charges in each of its FAC filings during the audit period.

Based on our review, the Company appropriately accounted for its purchased power costs in its FAC filings.

## VIII. OFF-SYSTEM SALES

When energy is available and when the market sales price is higher than the incremental cost of generating additional energy in a given hour, the Company participates in the sale of economy energy. The cost of fuel utilized for this determination is based upon a calculation involving the unit's heat rate and the incremental cost of fuel for a unit to be dispatched. *Table 8* provides a summary of off-system economy sales by year during the audit period.

**Table 8**
**Cleco Power, LLC**
**Summary of Off-System Sales**

| Year | Revenues Credited ($) | MWh | Revenue Per MWh ($) |
|---|---|---|---|
| 2009 | 2,221,775 | 70,492 | $31.52 |
| 2010 | 8,671,146 | 180,909 | $47.93 |
| 2011 | 6,125,425 | 115,836 | $52.88 |
| 2012 | 2,481,956 | 71,262 | $34.83 |
| 2013 | 776,102 | 22,633 | $34.29 |

The Company appropriately credited all sales revenue through the FAC so that ratepayers received the benefit of 100% of the margins created by these sales.

## IX. FUEL STABILIZATION – FINANCIAL AND PHYSICAL HEDGES

Due to the extreme volatility of natural gas prices in the years prior to the audit period, the Commission encouraged utilities to employ various mechanisms in an attempt to improve price stability while at the same time ensuring that service is delivered to ratepayers at the lowest reasonable cost. In Docket No. U-25729, the Commission provided insight regarding rate stabilization efforts by utilities.[1] In its July 20, 2001 Order, the Commission confirmed that it has become increasingly important to "diversify gas procurement practices and utilize hedging mechanisms in order to stabilize rates" while at the same time stating that "these activities must go hand in hand with the utilities' continued responsibility to procure fuel at the lowest reasonable cost." If these dual goals were pursued, the Commission stated it would not exercise hindsight and second guess the rates that were obtained by the utilities if they were obtained by "reasonable and prudent actions by the companies."

Cleco developed a Fuel Stabilization Policy defining its financial hedging program in 2001 and filed it with the LPSC. That policy was initiated in an effort to limit volatility in its FAC charges. Due to terminations of and changes to different purchase power contracts over the next five years, Cleco was required by the Commission to reevaluate its hedging program with assistance from LPSC Staff. The Company's hedging plans were revised in 2005 and 2006 and filed with the Commission in Docket Nos. U-27980 and U-28765, respectively. Those plans increased not only the hedging

[1] *See* U-25729, 7/20/01, In re: La. Gas Service Co. RSP; Trans La Gas Co. RSP; ELI and EGS, Inc approval to employ risk management tools to stabilize fuel and/or Purchase Gas Adjustment clauses

timing window but also the various types of hedging instruments utilized. The hedging plans called for increases in the forward-looking window for executing hedging instruments to as far out as 24 months. In addition to NYMEX futures contracts, the Company began using swaps and eventually call and put options. A complete description of each type of hedging instrument and related decision protocols used by Cleco for the audit period was supplied in response to LPSC 1-7, which is attached to this report as *Exhibit 4*. Since that time and through 2012, the Company continued to rely upon the direction provided to it by an outside hedging consulting firm, Pace Global Energy Services ("Pace"). The hedging decisions and instruments utilized were continuously monitored by Pace and the Company and modified as appropriate based on known and expected market conditions. A periodic report of activity and changing market conditions was generated for review by Pace and the Company as often as weekly during the audit period.

As noted in the prior FAC audit report, the hedging decisions made by Cleco prior to the audit period reduced volatility, but this reduction in volatility was achieved at a high cost to customers. In addition, FAC costs were increased in some years but also decreased in others as a result of the hedging activities. During the period from 2001 through 2008, it was a well-known fact that gas prices were extremely volatile with the market price for gas hard to predict. Henry Hub Prices spiked to over $15 per MMBtu in December of 2005, went as far down as just over $5 per MMBtu during August of 2007, and spiked again to over $13 per MMBtu in June of 2008. During 2008, there was no prevailing expectation that prices would decrease sharply and then remain relatively stable for a long period of time. As portrayed in *Exhibit 2*, that is exactly what happened. Gas commodity market prices in recent years have generally been lower and more stable than in prior years. The Henry Hub natural gas settlement prices during the audit period generally stayed within the $2 to $6 per MMBtu range and averaged just under $4 per MMBtu. Supply has been greatly increased by factors such as the unprecedented developments in shale extraction and the expanded gas infrastructure for gas delivery.

During the audit period, the Company reported that its hedging strategy again reduced price volatility, actual volatility percentages during the audit period were reported by the Company through discovery. Said percentages reported by the Company is as follows:

| | FCA Volatility (NYMEX Settle) | Cleco FCA Volatility Actuals |
|---|---|---|
| 2009: | 59% | 54% |
| 2010: | 52% | 33% |
| 2011: | 24% | 28% |
| 2012: | 44% | 40% |
| 2013: | 28% | 22% |

The first column refers to the annualized standard deviation of the month to month change in NYMEX settlement prices for natural gas. The second column reflects the same measure for Cleco's prices for natural gas included in the FAC filings. The data indicates that Cleco's price volatility was less than average for all annual periods except for 2011, especially during 2010.

Unfortunately for Cleco and its ratepayers during this audit period, there was a high price to pay for the reported reduction in volatility. Like most other utilities, the Company entered into long-term financial instrument hedges at about the same time when prevailing market prices had been extremely volatile and high and were expected to remain high during future periods. When prices started decreasing substantially near the end of 2008 and into the audit period, large losses from the settlement of the financial derivatives resulted. *Table 9* located on the next page is a summary of the net financial instrument hedging costs for the Company as reported for each of the applicable operating months during the audit period.

[redacted]

As reflected in *Table 9*, the Company incurred additional hedging related losses in each month through October 2012 and did not incur any net gains. This resulted in [redacted] million in costs charged to Cleco's ratepayers during the audit period, however, as mentioned above, the majority of these additional costs resulted primarily from the long-term hedges entered into before the beginning of the audit period.

The reported losses in 2009 and 2010 amounted to [redacted] million and [redacted] million, respectively, representing over 83% of the total losses reported during the five year audit period. The Company elected to place on hold the majority of its hedging practices as early as August 2010, and settlements of instruments executed before that date continued through July 2012 for those based on 24-month forward pricing. There were no settlements of derivatives that occurred after October 2012. The Company's hedging strategy was modified for a variety of reasons in addition to the conditions in the market. Prior to and at the beginning of the audit period, Cleco's operations were more heavily dependent upon high heat rate natural gas generation and purchased power to meet customer requirements. Starting in 2010, Madison 3 was placed in service and Acadia Unit 1 was acquired. While Acadia Unit 1 burns natural gas, it does so at a very efficient low heat rate. Both generation plant additions helped to lessen Cleco's dependence on natural gas as a fuel source and reduced the necessity to hedge. Cleco reserves the right to begin hedging again if prevailing conditions should warrant.

While the costs flowed through the FAC were very high for the hedged financial instruments due to unforeseen market conditions, we could find no evidence that the Company acted imprudently or that the costs incurred were improper. The Company and its hedging consultant continuously reassessed the condition of the markets as well as Cleco's desire to hedge for volatility reduction purposes. Those reassessments eventually led to the decision to discontinue its financial hedging practices as long as conditions warrant. We believe that decision was made timely and was appropriate.

Exhibit 1

# Cleco Power, LLC
## Cost of Fuel and Purchased Power
## Summary For All Cost Months from 2009 to 2013

| | Fossil Fuel MWhs | Economy & Emergency Purchases MWhs | Other Purchased Power Costs MWhs | Total MWhs |
|---|---|---|---|---|
| 2009 | 4,942,823 | 2,533,587 | 3,249,273 | 10,725,683 |
| 2010 | 8,752,614 | 3,147,213 | - | 11,899,827 |
| 2011 | 10,024,954 | 1,617,892 | - | 11,642,846 |
| 2012 | 9,143,044 | 936,005 | 1,233,392 | 11,312,441 |
| 2013 | 9,667,874 | 834,455 | 1,127,236 | 11,629,565 |
| Total | 42,531,309 | 9,069,152 | 5,609,901 | 57,210,362 |
| Percentage of Total KWhs | 74.3% | 15.9% | 9.8% | |

## Cleco Power, LLC
## Cost of Fuel and Purchased Power
## For All Cost Months in 2009

| | Fossil | | | Economy & Emergency Purchases | | | Other Purchased Power Costs | | | LA Retail Jurisdictional Factor | LA Retail Cost of Fuel |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Cost of Fuel | MWh | Cost/MWh | Cost of Fuel | MWh | Cost/MWh | Cost of Fuel | MWh | Cost/MWh | | |
| Jan-09 | $ 22,198,858 | 429,728 | $ 51.66 | $ 8,885,019 | 190,615 | $ 46.61 | $ 11,368,777 | 226,782 | $ 50.13 | 97.2642% | $ 41,291,235 |
| Feb-09 | $ 19,071,568 | 334,196 | $ 57.07 | $ 7,954,351 | 188,683 | $ 42.16 | 5,478,131 | 142,255 | $ 38.51 | 97.4326% | $ 31,669,541 |
| Mar-09 | $ 22,943,051 | 409,497 | $ 56.03 | $ 4,400,364 | 133,965 | $ 32.85 | $ 5,585,263 | 166,606 | $ 33.52 | 96.6403% | $ 31,822,374 |
| Apr-09 | $ 16,882,193 | 270,768 | $ 62.35 | $ 4,663,828 | 153,306 | $ 30.42 | $ 8,442,525 | 278,345 | $ 30.33 | 93.5786% | $ 28,062,861 |
| May-09 | $ 18,879,095 | 331,618 | $ 56.93 | $ 6,608,504 | 207,578 | $ 31.84 | $ 11,445,299 | 352,319 | $ 32.49 | 94.9803% | $ 35,078,977 |
| Jun-09 | $ 22,953,796 | 477,095 | $ 48.11 | $ 8,944,945 | 266,989 | $ 33.50 | $ 12,102,310 | 363,813 | $ 33.27 | 93.0962% | $ 40,963,306 |
| Jul-09 | $ 24,375,108 | 488,112 | $ 49.94 | $ 8,665,531 | 258,444 | $ 33.53 | $ 12,820,739 | 392,165 | $ 32.69 | 94.3409% | $ 43,266,037 |
| Aug-09 | $ 25,636,515 | 498,924 | $ 51.38 | $ 8,468,998 | 261,839 | $ 32.34 | $ 10,937,601 | 361,692 | $ 30.24 | 94.7068% | $ 42,658,893 |
| Sep-09 | $ 24,173,114 | 496,983 | $ 48.64 | $ 4,850,299 | 177,149 | $ 27.38 | $ 7,498,660 | 287,953 | $ 26.04 | 95.7531% | $ 34,971,018 |
| Oct-09 | $ 19,639,607 | 393,806 | $ 49.87 | $ 8,573,094 | 251,539 | $ 34.08 | $ 7,672,075 | 232,301 | $ 33.03 | 95.7448% | $ 34,357,807 |
| Nov-09 | $ 19,271,305 | 395,817 | $ 48.69 | $ 5,135,298 | 155,952 | $ 32.93 | $ 6,441,650 | 208,786 | $ 30.85 | 96.2563% | $ 29,693,388 |
| Dec-09 | $ 24,328,890 | 416,279 | $ 58.44 | $ 13,053,740 | 287,528 | $ 45.40 | $ 9,708,028 | 236,256 | $ 41.09 | 93.5300% | $ 44,043,893 |
| Total | $ 260,353,101 | 4,942,823 | $ 52.67 | $ 90,203,973 | 2,533,587 | $ 35.60 | $ 109,501,057 | 3,249,273 | $ 33.70 | | $ 437,879,329 |
| Percentage of Total KWhs | | 46.1% | | | 23.6% | | | 30.3% | | 100.0% | |

Cost of Fossil Fuel above includes Dolet Hills Deferral Adjustment and costs from Fuel Hedges

**Cleco Power, LLC**
**Cost of Fuel and Purchased Power**
**For All Cost Months in 2010**

| | Fossil | | | Economy & Emergency Purchases | | | Other Purchased Power Costs | | | LA Jurisdictional Factor | LA Cost of Fuel |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Cost of Fuel | MWh | Cost/MWh | Cost of Fuel | MWh | Cost/MWh | Cost of Fuel | MWh | Cost/MWh | | |
| Jan-10 | $ 25,849,787 | 590,033 | $ 43.811 | $ 26,594,163 | 470,405 | $ 56.535 | $ - | - | $ - | 88.8725% | $ 46,608,250 |
| Feb-10 | $ 23,808,097 | 619,545 | $ 38.428 | $ 11,964,282 | 302,587 | $ 39.540 | $ - | - | $ - | 94.8898% | $ 33,944,339 |
| Mar-10 | $ 23,810,432 | 671,209 | $ 35.474 | $ 6,715,012 | 177,199 | $ 37.895 | $ - | - | $ - | 96.2543% | $ 29,382,052 |
| Apr-10 | $ 25,531,986 | 613,131 | $ 41.642 | $ 5,233,649 | 154,488 | $ 33.877 | $ - | - | $ - | 96.3879% | $ 29,654,349 |
| May-10 | $ 31,874,205 | 842,298 | $ 37.842 | $ 5,859,126 | 168,266 | $ 34.821 | $ - | - | $ - | 91.7795% | $ 34,631,462 |
| Jun-10 | $ 33,685,434 | 862,980 | $ 39.034 | $ 13,312,031 | 295,418 | $ 45.062 | $ - | - | $ - | 93.8128% | $ 44,089,638 |
| Jul-10 | $ 31,263,660 | 752,413 | $ 41.551 | $ 21,473,153 | 439,542 | $ 48.853 | $ - | - | $ - | 91.8222% | $ 48,424,102 |
| Aug-10 | $ 34,853,323 | 864,654 | $ 40.309 | $ 17,706,511 | 370,621 | $ 47.775 | $ - | - | $ - | 91.9162% | $ 48,311,002 |
| Sep-10 | $ 26,168,853 | 744,054 | $ 35.171 | $ 12,044,261 | 317,827 | $ 37.896 | $ - | - | $ - | 95.7609% | $ 36,593,221 |
| Oct-10 | $ 22,909,560 | 707,144 | $ 32.397 | $ 5,885,754 | 173,415 | $ 33.940 | $ - | - | $ - | 90.8149% | $ 26,150,436 |
| Nov-10 | $ 24,187,866 | 723,299 | $ 33.441 | $ 2,799,025 | 84,149 | $ 33.263 | $ - | - | $ - | 90.1986% | $ 24,341,798 |
| Dec-10 | $ 28,328,400 | 761,854 | $ 37.184 | $ 8,578,441 | 193,296 | $ 44.380 | $ - | - | $ - | 89.3589% | $ 32,979,547 |
| Total | $ 332,271,601 | 8,752,614 | $ 37.963 | $ 138,165,406 | 3,147,213 | $ 43.901 | $ - | - | $ - | | $ 435,110,194 |
| Percentage of Total KWhs | | 73.6% | | | 26.4% | | | 0.0% | | 100.0% | |

Cost of Fossil Fuel above includes Dolet Hills Deferral Adjustment and costs from Fuel Hedges

## Cleco Power, LLC
## Cost of Fuel and Purchased Power
## For All Cost Months in 2011

| | Fossil | | | Economy & Emergency Purchases | | | Other Purchased Power Costs | | | LA Jurisdictional Factor | LA Cost of Fuel |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Cost of Fuel | MWh | Cost/MWh | Cost of Fuel | MWh | Cost/MWh | Cost of Fuel | MWh | Cost/MWh | | |
| Jan-11 | $ 31,843,598 | 905,014 | $ 35.186 | $ 2,860,587 | 73,569 | $ 38.883 | $ - | - | $ - | 88.5216% | $ 30,720,700 |
| Feb-11 | $ 28,477,122 | 783,707 | $ 36.336 | $ 3,299,328 | 11,485 | $ 287.273 | $ - | - | $ - | 89.6035% | $ 28,472,812 |
| Mar-11 | $ 27,059,521 | 748,648 | $ 36.145 | $ 2,097,740 | 62,177 | $ 33.738 | $ - | - | $ - | 90.7179% | $ 26,450,855 |
| Apr-11 | $ 27,014,063 | 728,015 | $ 37.106 | $ 5,397,235 | 135,423 | $ 39.855 | $ - | - | $ - | 96.4813% | $ 31,270,842 |
| May-11 | $ 28,235,858 | 740,744 | $ 38.118 | $ 10,052,450 | 243,841 | $ 41.225 | $ - | - | $ - | 96.1631% | $ 36,819,224 |
| Jun-11 | $ 37,513,985 | 966,819 | $ 38.801 | $ 9,866,734 | 218,254 | $ 45.208 | $ - | - | $ - | 93.3371% | $ 44,223,789 |
| Jul-11 | $ 38,239,996 | 1,010,984 | $ 37.825 | $ 8,177,332 | 188,910 | $ 43.287 | $ - | - | $ - | 93.2724% | $ 43,294,556 |
| Aug-11 | $ 37,682,251 | 1,029,904 | $ 36.588 | $ 12,224,038 | 287,030 | $ 42.588 | $ - | - | $ - | 96.1034% | $ 47,961,640 |
| Sep-11 | $ 30,631,698 | 839,937 | $ 36.469 | $ 4,229,867 | 115,207 | $ 36.715 | $ - | - | $ - | 93.8337% | $ 32,711,896 |
| Oct-11 | $ 25,990,135 | 761,813 | $ 34.116 | $ 2,669,063 | 94,473 | $ 28.252 | $ - | - | $ - | 92.0568% | $ 26,382,741 |
| Nov-11 | $ 23,242,237 | 711,653 | $ 32.660 | $ 2,905,309 | 85,946 | $ 33.804 | $ - | - | $ - | 89.5342% | $ 23,410,996 |
| Dec-11 | $ 26,171,047 | 797,716 | $ 32.807 | $ 3,450,674 | 101,577 | $ 33.971 | $ - | - | $ - | 89.4541% | $ 26,497,844 |
| Total | $ 362,101,510 | 10,024,954 | $ 36.120 | $ 67,230,358 | 1,617,892 | $ 41.554 | $ - | - | $ - | | $ 398,217,894 |
| Percentage of Total KWhs | | 86.1% | | | 13.9% | | | 0.0% | | 100.0% | |

Cost of Fossil Fuel above includes Dolet Hills Deferral Adjustment and costs from Fuel Hedges

**Cleco Power, LLC**
**Cost of Fuel and Purchased Power**
**For All Cost Months in 2012**

| | Fossil | | | Economy & Emergency Purchases | | | Other Purchased Power Costs | | | LA | LA |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Cost of Fuel | MWh | Cost/MWh | Cost of Fuel | MWh | Cost/MWh | Cost of Fuel | MWh | Cost/MWh | Jurisdictional Factor | Cost of Fuel |
| Jan-12 | $ 23,847,408 | 782,090 | $ 30.49 | $ 1,636,940 | 56,973 | $ 28.73 | $ 73,096 | 1,681 | $ 43.48 | 90.7000% | $ 23,180,602 |
| Feb-12 | $ 20,801,293 | 695,765 | $ 29.90 | $ 1,888,436 | 75,609 | $ 24.98 | 802 | - | $ - | 90.3441% | $ 20,499,555 |
| Mar-12 | $ 17,552,328 | 670,175 | $ 26.19 | $ 2,464,704 | 94,886 | $ 25.98 | $ 1,519,089 | 69,540 | $ 21.84 | 90.6211% | $ 19,516,269 |
| Apr-12 | $ 16,439,210 | 633,314 | $ 25.96 | $ 2,922,762 | 116,608 | $ 25.06 | $ 1,942,156 | 89,449 | $ 21.71 | 90.4570% | $ 19,271,076 |
| May-12 | $ 22,796,754 | 755,624 | $ 30.17 | $ 1,678,857 | 64,293 | $ 26.11 | $ 5,303,615 | 218,011 | $ 24.33 | 87.6315% | $ 26,095,982 |
| Jun-12 | $ 24,858,757 | 868,792 | $ 28.61 | $ 3,105,056 | 116,793 | $ 26.59 | $ 2,970,285 | 109,594 | $ 27.10 | 87.4577% | $ 27,054,251 |
| Jul-12 | $ 26,560,521 | 805,341 | $ 32.98 | $ 3,266,744 | 89,243 | $ 36.61 | $ 6,888,300 | 239,111 | $ 28.81 | 87.2763% | $ 32,043,986 |
| Aug-12 | $ 25,716,602 | 857,553 | $ 29.99 | $ 1,407,831 | 52,398 | $ 26.87 | $ 6,025,234 | 217,727 | $ 27.67 | 88.1930% | $ 29,235,686 |
| Sep-12 | $ 23,303,035 | 787,470 | $ 29.59 | $ 2,114,718 | 76,751 | $ 27.55 | $ 4,005,399 | 146,255 | $ 27.39 | 91.7027% | $ 26,981,824 |
| Oct-12 | $ 23,387,517 | 730,668 | $ 32.01 | $ 2,623,797 | 81,031 | $ 32.38 | $ 2,972,906 | 94,652 | $ 31.41 | 87.9075% | $ 25,479,302 |
| Nov-12 | $ 25,107,907 | 715,725 | $ 35.08 | $ 2,229,255 | 66,351 | $ 33.60 | $ 1,126,415 | 33,816 | $ 33.31 | 86.2472% | $ 24,549,038 |
| Dec-12 | $ 27,333,660 | 840,527 | $ 32.52 | $ 1,407,971 | 45,069 | $ 31.24 | $ 465,350 | 13,556 | $ 34.33 | 88.0025% | $ 25,702,872 |
| Total | $ 277,704,989 | 9,143,044 | $ 30.37 | $ 26,747,071 | 936,005 | $ 28.58 | $ 33,292,645 | 1,233,392 | $ 26.99 | | $ 299,610,444 |
| Percentage of Total KWhs | | 80.8% | | | 8.3% | | | 10.9% | | 100.0% | |

Cost of Fossil Fuel above includes Dolet Hills Deferral Adjustment and costs from Fuel Hedges

**Cleco Power, LLC**
**Cost of Fuel and Purchased Power**
**For All Cost Months in 2013**

| | Fossil | | | Economy & Emergency Purchases | | | Other Purchased Power Costs | | | LA | LA |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Cost of Fuel | MWh | Cost/MWh | Cost of Fuel | MWh | Cost/MWh | Cost of Fuel | MWh | Cost/MWh | Jurisdictional Factor | Cost of Fuel |
| Jan-13 | $ 27,024,478 | 845,518 | $ 31.96 | $ 2,435,506 | 78,985 | $ 30.84 | $ 212,616 | 5,439 | $ 39.09 | 86.5769% | $ 25,689,617 |
| Feb-13 | $ 21,999,210 | 694,894 | $ 31.66 | $ 2,167,666 | 71,766 | $ 30.20 | 46,128 | 361 | $ 127.78 | 89.0911% | $ 21,571,632 |
| Mar-13 | $ 21,564,028 | 721,710 | $ 29.88 | $ 2,501,896 | 70,038 | $ 35.72 | $ 6,373,638 | 172,737 | $ 36.90 | 86.7906% | $ 26,418,678 |
| Apr-13 | $ 20,974,290 | 641,109 | $ 32.72 | $ 4,277,572 | 131,927 | $ 32.42 | $ 2,162,580 | 54,560 | $ 39.64 | 88.9901% | $ 24,396,139 |
| May-13 | $ 21,564,028 | 721,710 | $ 29.88 | $ 2,501,896 | 70,038 | $ 35.72 | $ 6,373,638 | 172,737 | $ 36.90 | 86.7906% | $ 26,418,678 |
| Jun-13 | $ 28,891,217 | 988,533 | $ 29.23 | $ 2,578,866 | 72,608 | $ 35.52 | $ 3,054,346 | 76,615 | $ 39.87 | 87.7478% | $ 30,294,427 |
| Jul-13 | $ 30,657,677 | 1,026,056 | $ 29.88 | $ 2,259,621 | 68,070 | $ 33.20 | $ 2,667,508 | 53,296 | $ 50.05 | 87.8561% | $ 31,263,423 |
| Aug-13 | $ 31,972,262 | 1,029,772 | $ 31.05 | $ 2,181,379 | 69,483 | $ 31.39 | $ 3,279,105 | 85,845 | $ 38.20 | 87.5522% | $ 32,773,193 |
| Sep-13 | $ 28,871,403 | 954,643 | $ 30.24 | $ 2,152,742 | 64,725 | $ 33.26 | $ 3,347,500 | 91,054 | $ 36.76 | 87.6196% | $ 30,116,297 |
| Oct-13 | $ 23,038,464 | 785,507 | $ 29.33 | $ 1,827,198 | 57,602 | $ 31.72 | $ 2,754,389 | 71,070 | $ 38.76 | 89.7525% | $ 24,789,686 |
| Nov-13 | $ 19,445,941 | 637,193 | $ 30.52 | $ 1,701,222 | 51,976 | $ 32.73 | $ 5,092,205 | 159,290 | $ 31.97 | 87.9344% | $ 23,073,431 |
| Dec-13 | $ 19,927,985 | 621,229 | $ 32.08 | $ 6,495,828 | 414,900 | $ 15.66 | $ 6,209,338 | 184,232 | $ 33.70 | 85.4816% | $ 27,895,340 |
| Less: MISO Purchases and Sales Starting December 16, 2013 | | | | $ (5,458,146) | (387,663) | $ 14.08 | | | | | |
| Total | $ 295,930,982 | $ 9,667,874 | $ 30.61 | $ 27,623,247 | 834,455 | $ 33.10 | $ 41,572,990 | 1,127,236 | $ 36.88 | | $ 324,700,542 |
| Percentage of Total KWhs | | 83.1% | | | 7.2% | | | 9.7% | | 100.0% | |

Cost of Fossil Fuel above includes Dolet Hills Deferral Adjustment
MISO Purchases and related Sales were removed from this summary to compare costs and volumes with all other years. Cleco integrated into MISO on December 19, 2013.

Confidential

Exhibit 2

Exhibit 3

# Exhibit 3
## Cleco Power, LLC
## Average Henry Hub Index Price vs. Actual WACOG
## January 2009 - December 2013

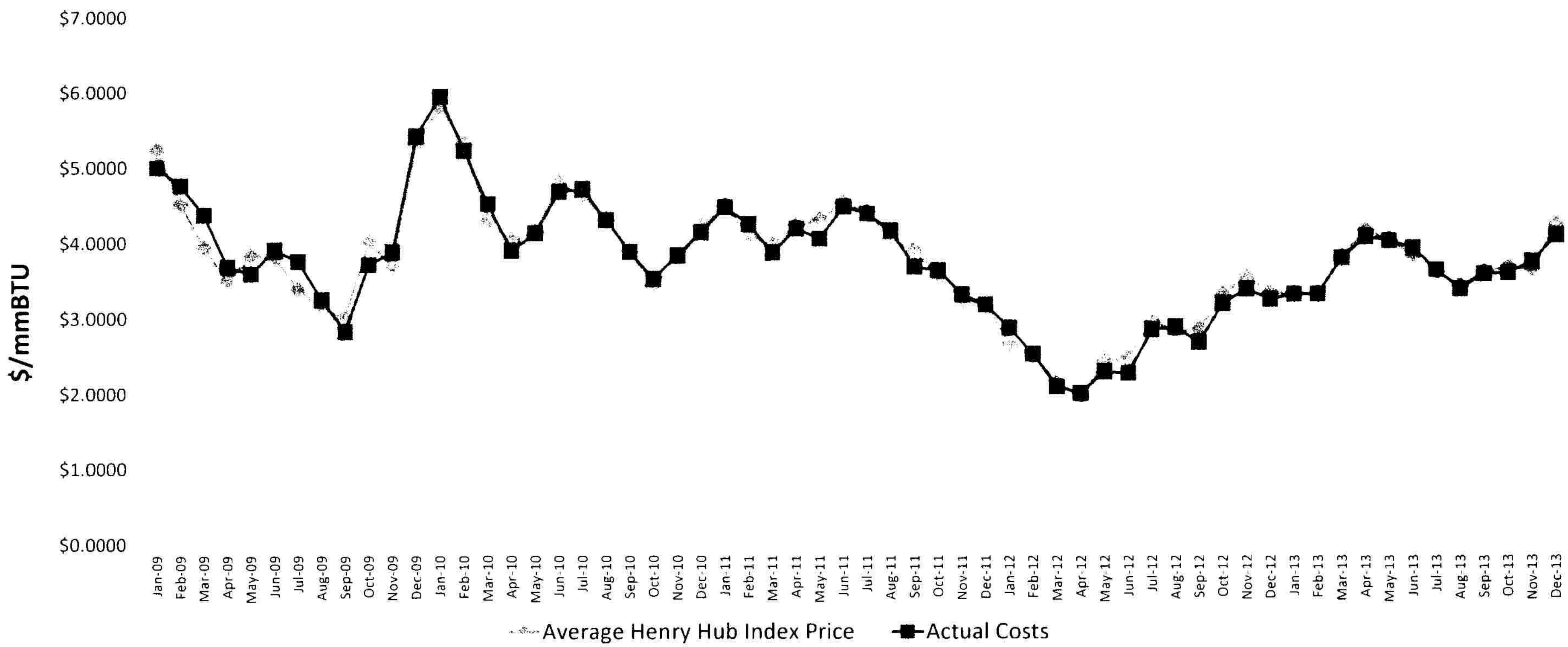

Exhibit 4

**BEFORE THE**

**LOUISIANA PUBLIC SERVICE COMMISSION**

**DOCKET NO. X-33325**

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**In Re: Fuel Adjustment Clause Audit for Cleco Power LLC for 2009 – 2013.**

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**RESPONSE TO LPSC STAFF'S FIRST SET OF DATA REQUESTS TO CLECO POWER LLC**

**DATA REQUEST LPSC 1-7**

Does the Company (or Company affiliate or outside party on behalf of the Company) utilize any financial derivatives in relation to its fuel expenses, e.g., hedges that protect against price changes? If so, please describe in detail all such derivative instruments used by the Company and reported in the FAC during the years 2009 through 2013. Provide copies of any documents that describe the Company's use of such derivative instruments.

**PREPARER: Marty Desselle, Supervisor – Natural Gas Procurement**

**WITNESS: Keith Johnson, General Manager Fuel Management**

**RESPONSE TO DATA REQUEST LPSC 1-7**

Financial derivatives used by Cleco to hedge:

I. The Company has utilized a variety of financial derivatives to hedge against the impact of market price movements on fuel expenses.
II. The derivatives instruments used include:
   a. Exchange-listed Henry Hub natural gas futures – NYMEX listed natural gas contract to purchase Henry Hub natural gas for a specified delivery month at a fixed price. Contract trades in 10,000 MMBtu increments. Physical settlement upon expiration.
   b. Over-the-counter Henry Hub natural gas swaps – bilateral natural gas contract to purchase Henry Hub natural gas for a specified delivery month at a fixed price. Financial settlement upon expiration.
   c. Over-the-counter Henry Hub natural gas call options – bilateral option contract that gives the buyer the right to purchase (call) natural gas from the seller for a specified delivery month at a fixed price. Buyer pays the seller an option premium payment at the time of contract execution. Financial settlement upon expiration.

d. Over-the-counter Henry Hub natural gas put options – bilateral option contract that gives the buyer the right to sell (put) natural gas to the seller for a specified delivery month at a fixed price. Buyer pays the seller an option premium payment at the time of contract execution. Financial settlement upon expiration.

III. Futures, swaps, and collars (purchase of a call and sale of a put) were used by the company to hedge the fuel expenses against a rise in prices.

IV. Put options were used by the Company to manage the hedge portfolio's exposure to mark-to-market ("MTM") losses that would occur in the event of falling prices.

Hedging program protocols and financial instruments use:

I. Programmatic Protocol
  a. Cleco's hedging program utilized a programmatic protocol to build a base quantity of hedges to protect against fluctuations in gas prices.
  b. Cleco had a programmatic target to hedge 30% of the forecasted gas volumes for each forward month.
  c. The 30% hedge was executed over a 6-month trading window, with 5% being added each month.
  d. The 6-month trading window for building the 30% hedge position was months 19-24 on the forward horizon. As an example, during the month of January 2009, Cleco would add 5% to the hedges for each of the forward months August 2010 thru January 2011 (months 19-24 on the forward horizon).
  e. Cleco used both OTC swaps and Exchange listed futures to build the 30% programmatic hedge position. No options were used as part of the programmatic protocol.
  f. Beginning in August 2010, Cleco elected to end the use of the programmatic protocol. The last programmatic hedge was executed on 7/30/2010, and covered the forward months ranging from February through July 2012.
  g. For forward months August 2012 through December 2013, Cleco did not execute any programmatic hedges.

II. Defensive Protocol
  a. Cleco's hedging program included a defensive protocol, where additional hedges are placed to protect against a rising market.
  b. The defensive protocol consisted of three boundaries that were set above the current market price, and in the event the market rose to those boundaries, Cleco would add hedges up to a predetermined target hedge ratio.
  c. In Cleco's program, a $1^{st}/2^{nd}/3^{rd}$ defensive boundary encroachment called for the hedge ratio to be increased to 50%/60%/75%.
  d. Cleco's defensive protocol called for the execution of swaps or futures contracts paired with a put spread, when a defensive boundary was breached. The swap or

futures contract protected Cleco against a further rise in prices, while the put spread provided some level of MTM protection in the event of a subsequent fall in prices.

III. Contingent Protocol
   a. Cleco's hedging program included a contingent protocol, intended to protect the hedge portfolio from incurring MTM losses beyond Cleco's tolerance for losses.
   b. The contingent protocol consisted of three boundaries that were set below the current market price, and in the event the market fell to those boundaries, Cleco would executing a put option strategy to protect the existing hedges from incurring further losses.
   c. Cleco's 1st/2nd/3rd contingent boundary encroachment called for 25%/75%/100% of the existing fixed price swap or futures positions to be covered by a put option strategy.
   d. Cleco's contingent protocol involved either executing an outright purchase of a put option or executing a put spread to protect an existing fixed price swap or futures position. Spreads were used to help mitigate the option premium spend associated with this strategy, but alternatively, provide less protection against MTM losses.

IV. Discretionary Protocol
   a. Cleco's hedging program included a discretionary protocol, allowing Cleco to add to the existing hedge position when the market appeared to be providing an opportunity to lock in low prices.
   b. Cleco relied on a proprietary Pace Global market signal to determine the timing of any discretionary protocol trades.
   c. The discretionary protocol was seldom used during the 2009-2013 period.